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(54) Title: INFLOW DETECTION APPARATUS AND SYSTEM FOR ITS USE

(57) Abstract

There is provided a method for monitoring fluid flow within a region to be measured of a subterranean formation, said method comprising placing at least one source within said subterranean formation; placing at least one sensor within said region to be measured, wherein each said at least one sensor is adjacent to at least one source such that said sensor measures changes to said fluid caused by said source; and providing at least one means for transmitting data from each said at least one sensor to at least one data collection device, said at least one data collection device capable of communicating with an operator.

INFLOW DETECTION APPARATUS AND SYSTEM FOR ITS USE

Field of the Invention

This invention relates to a method for measuring fluid flow in a subterranean formation; in particular measurements of flow rates of liquids, gases, and mixed fluids in subterranean formations.

Background

Recent developments in the oil drilling industry of well bore construction techniques such as horizontal wells and multi-lateral wells, present new challenges to the completion and reservoir engineering disciplines. High rate horizontal wells in deep water conditions further push the technology tools the petroleum engineer has available to safely and prudently produce the reservoirs.

Classical methods of reservoir monitoring assume the permeability ("K") and height ("H") of the zone contributing to the production of the well is known. This "KH" is often confirmed with production logs on a periodic basis and is typically considered constant. The KH of a well is paramount for most reservoir calculations. In a horizontal well or a multi-lateral well, the H of the well bore penetrating the reservoir is known from electric logging methods, and more recently by logging while drilling techniques. However, the logged reservoir interval may not be the same as the H actually contributing to the well production and, in fact, the H may change with time.

The industry has adopted a laze faire attitude relating to the assumption of inflow performance in horizontal and multi-lateral wells. Grand assumptions regarding inflow well performance are made based on

surface data (i.e. flow rates, pressures, water cut, etc.), possible down hole pressure gauges, and rules of thumb. The reality is that these assumption can lead to poor well performance, poor reservoir management, completion equipment failures, and in the worst cases, catastrophic failure of the well.

The only method currently available to the reservoir or production engineer to monitor changes or losses in "H" is to run a wire line or tubing deployed production log during well interventions. These logs are difficult to interpret, particularly in horizontal and high angle wells. This is due to the flow meters inability to measure the 3 phase flow rates, often referred in the literature as water hold up or gas blow by. This procedure of production logging requires a rig mobilization, resulting in lost production during the rig up and rig down of the logging equipment, and presents a risk of loosing equipment in the well. Production logging is not always possible (e.g. some subsea completions or wells in which an electrical submersible pump (ESP) is installed). Moreover, since the production logging data is subject to interpretation, the decision to run the production-logging suite is often avoided. The end result is that the production is maintained by increasing the choke size at the surface. This can result in more damage, and ultimately in screen and well bore failures or large hydrate production and blowouts.

Summary of the Invention

The method of the invention provides a means for monitoring fluid flow directly within a region to be measured of a subterranean formation, said method comprising:

placing at least one source within said subterranean formation;

placing at least one sensor within said region to be measured, wherein each said at least one sensor is adjacent to at least one source such that said sensor measures changes to said fluid caused by said source;

providing at least one means for transmitting data from each said at least one sensor to at least one data collection device, said at least one data collection device capable of communicating with an operator.

There is also provided a method for monitoring fluid flow in a region to be measured of a well bore, while the well bore is on-line, said method comprising:

placing at least one source selected from a thermal source, an acoustic source, and combinations thereof within said region to be measured;

placing at least one sensor selected from a thermal sensor, an acoustic sensor, and combinations thereof within said region to be measured, wherein each said at least one sensor is adjacent to at least one source such that said sensor measures changes to said fluid caused by said sources;

providing at least one means for transmitting data from each said at least one sensor to at least one data collection device, said at least one data collection device capable of communicating with an operator.

Detailed Description

The method of the invention provides a means for monitoring the flow of fluid, wherein fluid means liquids or gases or mixtures of liquids and gases, from subterranean formations. Measurement takes place directly in the region where a measurement is desired. In the case of a flowing well, the measurements may be taken while the well is producing. Thermal and/or acoustic sources are placed in the fluid flow path and sensors capable of detecting temperature or acoustic

changes placed near the sources detect changes to the fluid caused by the sources.

One embodiment of the invention provides a method for monitoring fluid flow within a region to be measured of a subterranean formation. At least one source is placed within the formation. Placement is relatively permanent, meaning the source is set and then left in the measurement zone. At least one sensor is also placed within the region to be measured. Each sensor should be adjacent to one or more sources, in close enough proximity to measure changes to the fluid caused by the source(s). It is necessary to also provide at least one means for transmitting data from the sensors to at least one data collection device. The data collection device may be subterranean, on the surface, or in the air but it must be capable of communicating with an operator. As used herein, an operator may be an object, such as an operating station, or a human.

The sources may be optical sources, electrical heat sources, acoustic sources, or combinations thereof. Examples include thermisters, optical heaters, continual heating elements, electric cables, sonar generators, and vibration generators. Because it is optimum to limit restrictions in the formation, the preferred sensors are optical fibres, which are small enough to be non-intrusive. The optical fibres may also act as the data transmission means, thereby serving two purposes. The sources and the sensors are preferably oriented perpendicular to the fluid flow.

When the subterranean formation is a well, the fluid flow region to be measured is typically within the well bore, be it vertical, horizontal or deviated. A means for deploying the sensors and data links in a fairly non-intrusive manner is via hollow tubular members.

The system of the invention is expected to perform well using applied well technology known as Micro Optical Sensing Technology ("MOST"). MOST allows for the miniaturization of sensing equipment in submersible equipment. Fundamentally, oil and gas well environments have restricted geometry and hostile conditions of temperature and pressure. MOST is able to function in these environments due to it's ability to use very small diameter data links (optic fibres) and to use sensors that can withstand temperatures above 200 °C.

Since the sources, sensors and data links are permanently installed in the desired region of the formation, there is no need for well interventions, such as production logging. The method can provide a continual inflow performance profile of the formation on a real time basis and multiple flow detection nodes along the formation can be monitored.

The use of thermal sources and sensors will be used as an example. A series of electrically or optically powered heat sources may be placed along a well bore axis parallel to a series of thermal sensors. The thermal sources may be in many forms, including but not limited to single point heating elements like thermisters, optical heaters, or a continual heating element like electric cable.

The heat sensors are preferably single or multiple optic fibres. The fibres may be deployed into the well in multiple means and in multiple geometry. An example of deployment which will protect the fibres from hydrogen exposure is to arrange the temperature sensors and data links in small hollow members, such as tubes. The flow detection system is formed by placing the optic fibres in the flow stream before the heaters, after the heaters, or both. Other embodiments uses the optic fibres and heaters deployed parallel to one another, surrounding one

another in coil configurations, and many other geometry's. The preferred embodiment places the heat source and thermal sensors perpendicular to the fluid flowing in the well bore, such that the heat source heats the fluid while the thermal sensors measure the heat change in the fluid stream flowing over the heat source. This system then forms a series of classic thermal flow meters according to the following simplified heat flow equation:

$$Q = Wc_p \ (T_2 - T_1)$$

where

Q = heat transferred (BTU/Hr);

W = mass flow rate of fluid (lbm/Hr); and

c_p = specific heat of fluid (BTU/lbm °F).

The accuracy of the flow meter is dependent on the accuracy of specific heat data for the flowing fluids. The specific heat of the fluids in the well will change with time, flowing pressures, and reservoir conditions (e.g. coning).

Optimum well production requires the heat sources and temperature measurement devices to be small and non-intrusive to the well bore inside diameter. Non-intrusive deployment allows for the well to be fully opened and thus allows for stimulation, squeeze, or logging techniques to be performed through the completion with the sources, sensors and data links permanently installed.

The preferred sensors and/or data links of the invention are optic fibres. Optic fibres are exotic glass fibres which are available with many different coatings and by various different manufacturing methods that affect their optical characteristics. Optic fibres have a rapid decrease in functionality when exposed to hydrogen, and of course subterranean water is a readily available hydrogen carrier. Therefore the fibres must be

placed in a carrier. But other characteristics of optic fibres allow one fibre to read multiple changes along the fibre's length, an obvious advantage.

Fibers may be used in oil and gas wells in conjunction with Optical Time Delay Reflectometry ("OTDR") devices (commonly referred to as "intrinsic measurement"). Intrinsic sensing along the fibre is done with application of quantum electrodynamics ("QED"). QED relates to the science of sub-atomic particles like photons, electrons, etc. For this application, interest is in the photons travelling through a very special glass sub-atomic matrix. The probability, or probability amplitude, of the photon interacting with a silicon dioxide sub atomic structure is known for each specialized optic fibre. The resulting back scattering of light as a function of thermal affects in the glass subatomic structure has a very well known relationship to the index of refraction of the optic fibre. Knowledge of the power and frequency of the light being pumped, or launched down the optic fibre allows for calculation of the predicted light and frequency emitted or back scattered at a given length along the optic fibre.

The process of the invention uses OTDR and thermal and/or acoustic sources to measure flow in wells. Flow changes at each node may be monitored versus time, providing a qualitative measurement on a permanent basis in real time. Knowing the glass and laser light being used, a back scattering returning power can be measured with "OTDR" according to the following equation:

$$P_{bs}(l) = \tfrac{1}{2} P_0 \Delta t v_g C_s NA^2 \exp\left(\int -2\alpha dx\right)$$

where

P_{bs} = backscattering power returning from distance l;

P_0 = launch power;

Δt = source time pulse width, in time units;

v_g = group velocity;

C_s = scattering constant;

NA = numerical aperture of fibre; and

α = total loss of attenuation coefficient.

OTDR can successfully and very repeatable measure the back scattering changes as a function of temperature caused by a laser pulsed light wave down an optic fibre, by relating Cs to and α.

$$C_s \cong (\alpha_r)_{co} + (\alpha_s)_{co} + P_c/P_t \ (\alpha_s)_d$$

and

$$\alpha = \alpha_{co} + P_c/P_t \ (\alpha_d)$$

where

α_r = Raman scattering coefficient;

α_s = Rayleigh scattering coefficient;

$(\ )_{co}$ = parameter associated with fibre core;

$(\ )_{cl}$ = parameter associated with fibre cladding; and

P_{cl}/P_{total} = ratio of total power exists in cladding due to evanescent wave effects.

The OTDR equipment uses a laser source, an optic fibre; a directional coupler connected to the fibre, an optoelectronic receiver, signal processing, and data acquisition equipment.

The method of the invention allows simple actions to be performed downhole without surface intervention, and allows reservoir performance downhole to be monitored using 4D seismic and other technologies. The present invention may also be applied to other flow processes (i.e. pipelines, refining processes, etc.). It will be apparent to one of ordinary skill in the art that many changes and modifications may be made to the invention without departing from its spirit or scope as set forth herein.

C L A I M S

1. A method for monitoring fluid flow within a region to be measured of a subterranean formation, said method comprising:

placing at least one source within said subterranean formation;

placing at least one sensor within said region to be measured, wherein each said at least one sensor is adjacent to at least one source such that said sensor measures changes to said fluid caused by said source;

providing at least one means for transmitting data from each said at least one sensor to at least one data collection device, said at least one data collection device capable of communicating with an operator.

2. A method according to claim 1 wherein said source is selected from an optical source, an electrical heat source, an acoustic source, and combinations thereof.

3. A method according to claim 2 wherein said source is selected from a thermister, an optical heater, a continual heating element, an electric cable, a sonar generator, a vibration generator, and combinations thereof.

4. A method according to claim 1 wherein said sensor is one or more optical fibres.

5. A method according to claim 1 wherein said one or more sensor and said one or more source are oriented perpendicular to said fluid flow.

6. A method for monitoring fluid flow in a region to be measured of a well bore, said method comprising:

placing at least one source selected from a thermal source, an acoustic source, and combinations thereof within said region to be measured;

placing at least one sensor selected from a thermal sensor, an acoustic sensor, and combinations thereof within said region to be measured, wherein each said at least one sensor is adjacent to at least one source such that said sensor measures changes to said fluid caused by said sources;

providing at least one means for transmitting data from each said at least one sensor to at least one data collection device, said at least one data collection device capable of communicating with an operator.

7. A method according to claim 6 wherein said source is selected from an optical source, an electrical heat source, an acoustic source, and combinations thereof.

8. A method according to claim 7 wherein said thermal source is selected from a thermister, an optical heater, a continual heating element, an electric cable, a sonar generator, a vibration generator, and combinations thereof.

9. A method according to claim 6 wherein said sensor is one or more optical fibres.

10. A method according to claim 9 wherein said sensors and data links are deployed in hollow tubular members.

11. A method according to claim 6 wherein said one or more sensor and said one or more source are oriented perpendicular to the fluid flow in said region to be measured of said wellbore.

INTERNATIONAL SEARCH REPORT

International Application No
PCT/EP 99/01397

A. CLASSIFICATION OF SUBJECT MATTER
IPC 6 E21B47/10

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 6 E21B G01F

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X Y	EP 0 442 188 A (TEXACO DEVELOPMENT CORP) 21 August 1991 see abstract see page 2, column 1, line 1 - line 21 see page 3, column 3, line 32 - column 4, line 30; claim 1 ---	1-3,6,7 4,9,11
X	EP 0 481 141 A (TEXACO DEVELOPMENT CORP) 22 April 1992 see abstract see page 2, column 1, line 1 - line 35 see page 2, column 2, line 4 - line 10 see page 3, column 3, line 42 - column 4, line 31; claims 1,2 --- -/--	1-3,6,7

[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

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"E" earlier document but published on or after the international filing date

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

"&" document member of the same patent family

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C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication,where appropriate, of the relevant passages	Relevant to claim No.
X Y	FR 2 707 697 A (FIS) 20 January 1995 see page 2, line 30 - page 3, line 23 see page 6, line 20 - page 7, line 11; claims 1,2; figure 4B ---	1-3,5 11
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INTERNATIONAL SEARCH REPORT

Information on patent family members

In ational Application No
PCT/EP 99/01397

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